CITY OF LODI

COUNCIL COMMUNICATION

AGENDA TITLE: Presentation on the Central Valley Energy Facility (LM6000)

MEETING DATE: November 15, 2000

PREPARED BY: Electric Utility Director

RECOMMENDED ACTION: Information only.

BACKGROUND INFORMATION: The Northern California Power Agency (NCPA) Combustion Project No. 2 (STIG) site was originally sized to accommodate two combustion turbine units. City needs and market economics now make it feasible to pursue construction of a second generating unit at the site. Acquisition of another generation resource will reduce the City's exposure to high power market prices as well as provide the opportunity for power market sales revenue which would be used to offset the City's bulk purchased power costs.

As the presentation will show, the project is unique in its partnership, its very ambitious construction schedule and the potential rewards for helping alleviate California's electric power crisis. Please refer to attached Exhibit A and B.

FUNDING: Not Applicable

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Lodi LM6000 Project
Executive Summary and Recommendation

Plant Description and Ownership Shares

The NCPA CT2 participants have a unique opportunity to add approximately 45 MW of additional capacity at the Lodi STIG facility. The proposed new unit, a GE LM6000 aero-derivative combustion turbine, would have ownership shares of 19.0% for Alameda, 39.5% for Lodi, 5.0% for Lompoc, and 36.5% for Roseville. This site was initially developed anticipating the possibility that an additional generating unit could be constructed within the existing site boundaries and utilize certain already installed facilities more efficiently and effectively. NCPA's Generation Services Business Unit provides full operations and maintenance support for the existing STIG plant and the operations and maintenance of the new LM6000 unit would require only one additional plant operations staff.

Why Build this Unit Now

A healthy California economy, strong electric load growth, and recent power industry deregulation have contributed to a dramatic need for new generation facilities within California. Further, participating NCPA members have an established joint business venture in the Lodi STIG which can efficiently support the proposed generation unit. This physical and business situation, coupled with volatile wholesale power prices and changes to the Western Power Administration contract which will make it more like a hydroelectric plant, make it prudent to consider new generation to provide for current and future retail load growth at stable and predictable power production cost.

Moreover, the California ISO has issued a Summer 2001 and beyond new capacity RFP which has the potential to provide payments of $8 million per year, for three years, for the proposed LM6000 unit. Enron is currently negotiating this contract with the ISO. But for building this plant now with a July 2001 on line date, these ISO capacity payment monies would not be available.

Thus the combination of an ideal physical location, added plant O&M scale economies, regional generation deficiency, retail load growth, annual Western contract variability, and the need for stable and predictable power supply cost suggest that swift action is warranted to pursue this project.

Project Economics

The CT2 participants would buy the new unit for about $44 million on July 2001. Enron would assign the 3-year, $24 million ISO capacity contract to the CT2 owners. This brings the effective purchase price of the plant into the $20 million range. Using a very conservative view of future power prices and natural gas fuel supply cost, suggests an expected present value benefit of over $23 million over the first ten years of plant operation. New unit economics are more fully detailed in the project description, summary and recommendation report.

Recommendation

It is recommended that the CT2 Project owners:

- Subscribe to their full participation shares in the LM6000 Project.
- Take full title to the unit for $43.9 million on 7/01 (or upon the date of commercial operation).
- Take appropriate steps to secure the necessary authorities to finance or pay for such unit.
- Negotiate contracts with Enron to provide for the purchase of such unit with requisite guarantees on 1) purchase price, 2) ISO capacity contract payments, and 3) unit on-line date.

Lodi LM6000 Project Summary Description, Assessment and Recommendation

1) BACKGROUND

During the early 1990s the Cities of Alameda, Lodi, Lompoc and Roseville underwrote the construction and operation of what is commonly called NCPA Combustion Turbine Project No. 2 (CT2) in Lodi, California. The site, on a 10 acre parcel leased from the City of Lodi, consists of a steam injected LM5000 General Electric turbine nominally rated at 49.9 MW. The plant commenced commercial operation during mid-year 1995. The ownership shares of the NCPA participants in this project are 19.0% for Alameda, 39.5% for Lodi, 5.0% for Lompoc, and 36.5% for Roseville. The site was developed anticipating the possibility that an additional generating unit could be constructed within the existing site boundaries. Both the gas service pipeline and the connection facilities with PG&E's 230 Kv transmission system are sized to accommodate additional generation.

A healthy California economy, strong electric load growth, and recent power industry deregulation have contributed to a dramatic need for new generation facilities within California, in general, and specifically in the Sacramento Valley Region. Even during the relatively mild Summer 2000 period, the Sacramento Valley Area was subject to numerous ISO imposed Stage 2 Emergency Alerts (reserve margins falling below 5%). The ISO, in attempting to help assure appropriate power system reliability, initiated an RFP for new generation capacity to be on-line by Summer 2001 --- a very fast track for new generation. The ISO received approximately 3,000 MW of bid responses to its RFP which will result in substantial capacity payments being made to selected bidders during the annual sub-period June through October. ENRON responded to the ISO's RFP by bidding multiple installations of GE LM6000 plants in and around Northern California. A prime site for the installation of such unit is the existing NCPA CT2 location.

The CT2 owners have entered into a preliminary arrangement with ENRON to pursue the potential of installing the proposed LM6000 45 MW unit at the CT2 site. Discussions continue to include having NCPA staff provide unit operations and maintenance, approval of equipment specifications, and provisions for the CT2 project owners to take ownership of the LM6000 unit either upon commercial operation or at some defined future date. This report will discuss the advantages and business structures associated with the construction of the proposed LM6000 unit at the CT2 location.

2) CT2 SITE OWNERSHIP AND NEW UNIT SHARES

As indicated above, the existing CT2 LM5000 unit is owned by the Cities of Alameda, Lodi, Lompoc and Roseville. The construction of any additional facilities within this site will initially be offered to the current participants based on CT2 participation shares. It is possible, however, that one or more of the CT2 participants will not want their proportionate share of any newly constructed unit. In this event, those participants that desire more than their proportionate share may "step up" their percentages until the new unit is fully subscribed. The following table outlines possible LM6000 ownership shares (percentages and MWs) under various allocation and step up scenarios.

Existing CT2 and Proposed LM6000
Pro Forma Allocation Shares

Participant	CT2, LM5000		LM6000, All Share		LM6000, LD, LO, RO		LM6000, LD, RO	
	%	MW	%	MW	%	MW	%	MW
Alameda	19.0	9.5	19.0	8.6	-	-	-	-
Lodi	39.5	19.7	39.5	17.8	48.8	22.0	52.0	23.5
Lompoc	5.0	2.5	5.0	2.3	6.2	2.8	-	-
Roseville	36.5	18.2	36.5	16.4	45.1	20.3	48.0	21.6
Total	100	49.9	100	45.1	100	45.1	100	45.1

The prior table is for illustration purposes only and uses an LM6000 nameplate capacity rating of 45.1 MW. Depending upon the ultimate configuration installed, the capacity could vary between 40 and 50 MW. Also, the percentage shares may be negotiated between the participants. The participants may also negotiate a scheme whereby one or more of the CT2 owners do not initially participate in the LM6000 unit but rather buy into this unit a number of years after commercial operation from the initial participants. This report does not suggest or recommend initial LM6000 participation levels and assumes that either each participant will subscribe to their CT2 percentage or will negotiate between and among themselves to determine LM6000 ownership percentages.

3) NEW GENERATION NEED

There are multiple circumstances indicating a need for additional generation capacity by NCPA members specifically, and within Northern California generally. These include:

- <u>Buildout of Existing Site</u>

  The CT2 site is ideally suited to the addition of an LM6000 unit. It will fit within the existing 10 acre parcel containing the CT2 LM5000 unit. Both the 230 KV interconnection with PG&E and the natural gas pipeline supply service have been sized to incorporate an additional unit and only minimal adaptation is necessary to tie into these facilities. Additionally, the new unit will have access to the water source provided by the White Slough Treatment Plant. Certain other existing equipment such as gas compressors, fire suppressant, control room facilities, and other available equipment that does not have to be redundant support the construction of a new unit at this site. There will be some potential, even after the LM6000 unit is installed, to add additional capability from a heat recovery turbine tied to the existing LM5000 and the proposed LM6000 units. Given this outcome, this would represent the full build out of this 10 acre location.

- California Power Plant Vintages

  The California ISO projected a California Summer 2000 peak load of 48,600 MW. Due to the relatively cool summer that occurred, actual California peak load did not reach this level. Assuming a need for a 15 percent operating reserve margin to cover the peak along with any potential planned and unplanned outages, California needs a dependable capacity base of about 56,000 MW, either through capacity built in California or from dependable import capability. As of August 1998, the California Energy Commission's "Power Plant Database" indicates a 53,743 MW installed capacity base in California. And over 70% of this installed capacity is over 30 years old. While it is possible to keep older power plants running with proper care and maintenance, many of these plants are relatively inefficient in terms of fuel use and do not have the ability produce electricity all hours of the year (air pollution constraints, for example). Major site repowering can resolve some of these reliability and efficiency issues but it is not unlikely that California will need to add about 10,000 MW of capacity over the next 10 years just to replace dated existing capacity.

- California Load Growth

  California's total power demand has been growing rapidly over the last five years. Assuming existing capacity of about 54,000 MW coupled with a conservative 2%/year load growth over the next ten years, suggests a need for an additional 12,000 MW of new generation capacity. And this estimate excludes the impact of declining imports into California as load growth and capacity demands increase in the other states comprising the Western Systems Coordinating Council (WSCC).

- Proposed Capacity Additions

  California currently has about 5,000 MW of new capacity in various stages of construction and about another 5,000 MW in the "thought" and/or permitting process. Note that this 10,000 MW total is less than half of the capacity that could realistically be needed over the next 10 years in California. For NCPA local distribution utilities that are not fully resourced and/or are experiencing significant load growth, this indicates a potential shortage of generation and the higher prices and system reliability concerns that will result. To the extent that lights do stay on in NCPA member service territories, load will be met with either existing generation, new generation, longer-term contract purchases, or short term energy market purchases. With respect to this latter source, the short term energy market has experienced extreme price volatility over the last 18 months. Future California capacity shortages will only exacerbate energy price volatility (subject to actions taken by the CPUC, FERC, ISO Board, and the State Legislature to control such situation).

- NCPA Member Load Growth

  Apart from the general need for new generation capacity in California to meet state-wide load growth, NCPA members are also experiencing load growth associated with economic and population expansion in their service territories. The following table outlines the preliminarily projected capacity and energy growth rates for the CT2 owners over the 2000 through 2010 period.

CT2 Owners' Capacity and Energy Needs (2000 - 2010, Average Hydro Conditions)								
Participant	Year 2000		Year 2010		10-Year Change		Annual % Growth Rates	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Alameda	73.4	394	96.6	525	23.2	131	2.8	2.9
Lodi	136	446	157	513	21	67	1.4	1.4
Lompoc	26.5	135	29.1	148	2.6	13	0.9	0.9
Roseville	277	1006	457	1626	180	620	5.1	4.9
Total	513	1981	740	2812	227	831	3.7	3.6

The prior table shows the forecasted capacity and energy needed by the CT2 owners between 2000 and 2010. This table does not take into account existing capacity owned or under contract by the participating cities. The following table displays the estimated net capacity and energy positions for the CT2 owners for the years 2001, 2004, 2005, and 2010 (essentially taking the above capacity and energy needs and subtracting existing resource/contract commitments).

CT2 Owners' Net Capacity and Energy Balance (2001, 2004, 2005, 2010; Average Hydro Conditions)								
Participant	Year 2001		Year 2004		Year 2005		Year 2010	
	MW	aMW	MW	aMW	MW	aMW	MW	aMW
Alameda	+26	+12	+16	+0.3	+26	-2.5	+9	-14.4
Lodi	-2.6	-8.4	-11.5	-12.8	-7.0	-14.2	-19.1	-19.9
Lompoc	-1.8	-6.8	-3.5	-8.0	-1.2	-8.5	-3.3	-10.1
Roseville	-84	+10	-146	-15	-185	-56	-297	-132
Total	-62	+7	-145	-36	-167	-81	-310	-176

The above table does not address the potential use of the proposed LM6000 unit to provide a hedge against forced resource outages, load growth which exceeds the forecast, or extremely dry hydro or unusually hot weather conditions. Each of these conditions can, to some degree, be mitigated by having additional resources such as the LM6000 unit.

- Price Volatility Hedge

Energy prices in the deregulated California power marketplace have demonstrated severe volatility over the last year and a half without any proposed mechanisms that can realistically stabilize such prices. The ISO has recently approved a scheme to cap California energy prices as a function of gas prices and time of day, but it is not yet known whether this action will be either effective or permanent. One relative advantage municipal power companies have over California investor owned utilities is that they remain vertically integrated; that is, municipals can build and operate generating stations to 1) assure that they have ample capacity to meet load, and 2) accurately predict the cost to serve such load. This is significantly different from the California IOU situation which results in the IOUs being market "price takers" when purchasing energy to meet load.

And market prices since the IOUs divested their power resources have become increasingly volatile, with average prices increasing sharply. Evaluating NP15 prices over the period from September 1999 through August 2000, indicates an average price of $67 per MWh, over all hours of the one year period. The average price for the highest priced 25 percent of the hours over the same period was $173 per MWh, a reasonable proxy for the average cost to serve the 8 hour weekday peak period throughout the year. Also, the trend was for average price to rise during the latter portion of the period which may indicate the influence of undue market power by the generators or the bidding generators simply realizing that they can "game" the marketplace faster than the ISO or regulators can change the rules. In any case, the current real time marketplace does not appear to be a cost effective and predictable place to procure needed wholesale power supply.

The ISO Board approved yet another price cap scheme during the October 26, 2000 Board Meeting. The vote was 13 for and 10 opposed, hardly indicating full support for the proposal which was strongly opposed by generators. The approved arrangement allows the cap to vary as a function of Henry Hub gas price and the ISO forecasted hourly load level. The cap, given a $6.00 per MMBtu gas price varies from a low of $65 per MWh to a high of $250 per MWh when statewide load levels exceed 40,000 MW. This scheme was rejected by FERC Order dated 10/31/00 which provided certain other changes which may affect price caps in California.

Price caps can be significant when considering new generation options. If the caps are set below the operating cost of proposed new resources and sufficient generation is forthcoming, one should buy from the market and avoid the cost of a new plant. On the other hand, price caps may simply reduce or eliminate the construction of new generation if the caps prove too low to recover projected new plant capital, fuel, and O&M costs. Thus a municipal power company relying on the wholesale market for power supply may not be certain such supply will be available when needed. Another concern facing the municipal constructor of a new plant to meet load is the prospect of attaining revenues from the wholesale marketplace when such generation capacity is surplus to its load at certain times of the year, month, or day.

Actual August 2000 hourly NP15 prices averaged $194/MWh. Application of the price caps approved by the ISO board on 10/24/00 would result in an average hourly price of $103/MWh, still high by historic standards but only about half of the price that actually occurred. Building a plant will reduce potential price volatility and provide needed capacity. Based on recent market rule changes and an incessant array of price cap revisions, the economics of the plant should be based primarily upon serving native load requirements and not the expectation of high market derived revenues. The economic evaluation section below will examine the potential impact of lower market prices.

- Western Power Firming Need

Commencing 2005 Western power allocations, at this juncture, will be very much akin to a hydro project. That is, on dry hydro years, energy delivered will be reduced accordingly and Western customers will have to supplement their energy supplies from the marketplace, long-term firming contracts, new generation sources, or some combination of these alternatives. This change in the Western delivery capability is primarily responsible for the increased energy requirement of 45 aMW of the CT2 owners between 2004 and 2005. The proposed LM6000 project with the environmental capability to operate 24 hours/day can provide a reliable source of such energy at a cost that will likely be at or below market prices even if caps remain in place. During August 2000, as discussed above for example, even with the load based caps, 75% of the month prices would have been $95/MWh or greater, with an average price during this period (about 550 hours) of $125/MWh. The LM6000 unit with a 9500 Btu/KWh heat rate and $6/MMBtu gas would produce energy at a cost of about $60/MWh (fuel plus variable O&M only).

- ISO Capacity Payments

  Enron, the proposed constructor of the LM6000 project, bid into the ISO Summer 2001 capacity RFP. While this RFP is not yet final, the LM6000 project has made the initial screening and ENRON and ISO staff are negotiating payments to be made annually over a three year period given swift construction and operation of the LM6000 unit (proposed on line 7/1/01). These payments could be in the range of $8 million a year for three years.

  The ISO needs this new capacity to help prevent system emergency situations in NP15. ENRON's receipt of such contract from the ISO (which will be assignable to NCPA if the CT2 owners purchase such plant), allows one way to offset the construction cost of the unit. While it may have been desirable for NCPA to RFP the CT2 site to see what other arrangements might have been available from other market players, the simple fact is that if ENRON consummates the ISO capacity bid contract, there is no way NCPA or any other entity could build this unit and get the funding from the ISO. Thus, a unique opportunity exists to offset much plant construction cost and further reinforces the reasons that NCPA is, at this time, dealing exclusively with ENRON regarding the CT2 site.

4) Proposed LM6000 Hardware Configuration

The LM6000 proposal is more fully described in the Initial Study and Mitigated Negative Declaration for the Central Valley Energy Facility Project published October 2000 in conjunction with the necessary environmental scoping and reporting associated with the proposed new plant. In this report the plant is assumed to be on line July 1, 2001 and have a net nameplate rating of 45.1 MW. Further, the plant will be able to generate 24 hours/day, throughout the year without any energy output restrictions. Further, the unit will fit within the bounds of the existing CT2 site and be operated and maintained by NCPA's Generation Services Business Unit. One additional staff person will be required to provide routine maintenance and to operate the unit.

5) Project Alternatives Considered

There are three project alternatives considered in this report:

A) No action - do not construct project;

B) ENRON constructs and owns plant through 11/1/04; and,

C) ENRON constructs and CT2 owners buy plant upon commercial operation, 7/1/01.

Option A

As discussed earlier in this report, the ISO capacity payments, if attained, present a unique opportunity to offset a significant portion of the construction cost of this project. If that contract is not consummated, then ENRON will not construct the plant and the site will not be built out in the immediate future. If this were to happen, NCPA staff, in conjunction with the CT2 participants, will evaluate other ways to use the remaining capability at the CT2 site consistent with market alternatives and the need to meet load and Western contract changes. In the event that NCPA were to later proceed to construct an additional unit on this site it would likely come on line during the summer or fall of 2002, at the earliest, at a potential construction cost in the range of $30 - $35 million for a project similar to that proposed by ENRON. It must be noted that there can be considerable construction cost uncertainty given the recent shift from a buyer's to a seller's market in generation capacity. Moreover, NCPA expended over $70 million during the construction of the CT2 unit -- a total exceeding $1400 / KW.

Option A assumes that CT2 owners simply buy a market equivalent 30% load factor "plant output" at current and future market prices.

Option B

This alternative has ENRON constructing and owning the unit from the date of commercial operation through 11/1/04. During this period, ENRON would receive the rights to all unit output and resultant market revenues along with all ISO summer capability payments. NCPA staff would perform all operation and routine maintenance functions at the facility for a a management fee plus the fully loaded cost of a plant operator. NCPA would pay for a plant inspection approximately 90 days prior to change of ownership to assure that the plant condition was at least average for a 3 year old plant with a similar number of operating hours. ENRON would be required to fix any significant mechanical deficiencies with a capped obligation of, say, $1 million.

Initial discussions focused on this option with an 11/1/04 proposed transfer price in the range of $300/KW, or about $13.5 million. ENRON has indicated that the cost to install the unit has increased substantially (to about $44 million) and that this, with further refinement of its tax and interest calculations, results in a transfer price likely to be in the $600 - $800 per KW, or up to $36 million.

<u>Option C</u>

This option includes the participating CT2 owners purchasing the LM6000 unit on the date of commercial operation, targeted to be 7/1/01. The full purchase price for the unit will be $43.9 million. The NCPA CT2 participants will receive all payments resulting from the ISO summer capacity contract (nominally, $24 million) and, if desired, $12 - $14 million for a call option purchased by ENRON for plant output from unit commercial operation date through 11/1/04.

In short, for the first 3 plus years it would be essentially ENRON's unit with the right to call on it and operate it as it deems prudent. NCPA would receive the revenue from the ENRON call option and all ISO capacity payments. After 11/1/04, the plant would be operated per the instructions of the CT2 participants and ENRON ceases to be involved in the plant.

6) Economic Assessment

NCPA evaluated Options A, B, and C, and performed sensitivity analyses to project the impacts of changing natural gas prices and the market price of available energy.

Basic Input Assumptions Included:

Discount Rate	7.5% (Consistent with capital cost)
Natural Gas Price	$6.50 / MMbtu
Annual Capacity Factor	30% (As a function of gas price)
Average Energy Price	$154/MWh (Based on NP15 9/99 - 8/00)
Escalation Rate	3.5% / Year
Evaluation Period	10 Years, 2001 - 2010

The evaluation was performed using discounted cash flow techniques with capital expenditures assumed paid from cash on hand. Additional sensitivity was performed to assess the impacts of financing the plant over time.

The Options were evaluated using a 10 year time horizon. One variant of Option 3 was reviewed which assumed that the CT2 owners would not sell the call option to ENRON over the first three years and instead sold any unused plant output into the market whenever market price exceeds plant incremental fuel plus variable O&M cost. The "benchmark" case assumes that the LM6000 owners would have otherwise had to buy the equivalent MWh plant output from the marketplace at the time it would otherwise have been economic to run the plant.

The $154/MWh average market price is based on the actual NP15 ex post hourly price duration curve covering the period September 1999 through August 2000. The average price for all hours of the year is $67/MWh. The average price for the highest priced 30% of the hours is $154/MWh. Using a conservatively high delivered gas price of $6.50 per MMBtu results in the plant "running" at a 30% capacity factor and thus receiving an average of $154/MWh for all energy sold; the average production cost given $6.50 gas is about $65/MWh which includes fuel plus variable O&M.

10-Year Economic Summary Table (7/2001 Present Value)		
Case	NPV Cost $MM	Benefit v. A, $MM
A: Buy 45 MW/hr (118,260 MWh per year) at an average price of $154/MWh (in 2001 dollars)	$ 144	-
B: CT2 Owners take title to plant on 11/1/04 for $36MM. Enron receives all interim rights to plant energy and ISO capacity payments	$ 122	$ 22
C.1 CT2 Owners buy plant on 7/1/01 and receive all ISO capacity payments and a $12MM premium for selling a 3-year plant call to Enron	$ 102	$ 42
C.2 CT2 Owners buy plant on 7/1/01 and get the ISO capacity payments and full rights to all plant output (no call sale to Enron)	$ 88	$ 56

The above cases were developed assuming that any monies paid by the CT2 owners to Enron for the purchase of the plant were paid in a lump sum from cash on hand; no bonded debt or other borrowing is assumed to occur. If participants were to issue debt as in Case C.2, for example, the 10-year present value cost drops to $73 million, just about half of the Case A market alternative. Another alternative assessed is that the CT2 owners build a plant without Enron involvement which comes on line in 2002 at a total construction cost of about $34.5 million. The 10-year net present value cost of this outcome is $106 million.

From an economic perspective, the best outcome is to take immediate possession of the plant, receive the ISO capacity payments, and use plant out to either sell into the market or to serve native load and thus avoid market purchases.

7) Sensitivities

Several factors may significantly effect the economic results reported herein. These include long term gas prices, new technologies, actions of regulatory and legislative bodies, the availability and price of power from the marketplace, and dry hrdro year impacts.

- Gas Prices

  Burnertip gas prices in California were at historic lows in the mid 1990s at about $2.25 per MMBtu. A 10,000 MMBtu/KWh plant produced energy at a cost of only $22.50 per MWh and, indeed, these low gas prices were instrumental in the historic low power prices during the same period. Summer 2000 gas prices reached over $6.00 per MMBtu and the fuel only price of electricity produced from gas reached $60.00 per MWh for relatively efficient plants. Gas tends to be the fuel used to fulfill peak energy requirements. Generally there is a high correlation between gas price and electric energy price. This is an important point when considering the construction of a gas fired unit of medium efficiency, and tends to reduce the plant's economic sensitivity to changing gas prices. If gas prices increase the market price of energy increases accordingly; falling gas prices result in falling energy prices.

  Gas prices are not expected to significantly affect the economics of the proposed LM6000 project.

- New Technologies

  There has been much recent discussion on distributed generation: the ability to build smaller, relatively efficient generators near load. This could have an impact on the economic feasibility of new conventional gas fired plants. There has not yet been sufficient penetration of distributed generation to have a significant impact on the need for conventional resources and it is not considered to have an impact on LM6000 project economics over the next ten years or more.

- Regulatory Actions

Regulatory actions can restrict plant locations, type of pollution control equipment required and the total annual plant output. The proposed LM6000 will have no run time restrictions due to the acquisition of sufficient emissions credits. Regulatory actions to limit market price will likely have more potential impact on LM6000 economics than pollution related restrictions. Indeed, the ISO Board has taken action over the last year and a half to raise the price cap from $250 to $500 to $750 per MWH and then to reduce the cap to $500 to $250 and most recently to impose load level price caps between $65 and $250 per MWh. The reduction in price caps, however, is not likely to engender a rush of new generation into California. Indeed, the proposed LM6000 project and the expected $8 million annual ISO payments over the next three years are the result of the ISO attempting to fill a potential 8,000 MW generation deficit forecast for summer 2001.

And for the municipal participants in the LM6000 project, the new capacity will fill only a portion of existing and future known energy and capacity needs. Thus while caps will have an impact on market price, the generation is needed to serve load. Only lower prices with a surplus of generation capacity would have an adverse impact on LM6000 economics; and this outcome is counter intuitive.

It is also possible that the FERC may re-establish cost of service regulation for California generators. Several investigations are currently underway which may prove that undue market power has been used in California to boost power prices beyond competitive levels. FERC may use these studies as a basis to force generators to sell power a cost plus a prescribed reasonable rate of return. The LM6000 project would already be priced at cost when energy is delivered to municipal end use customers and thus external regulatory actions would have minimal impact on the need for, or the cost effectiveness of, this unit to meet native load.

- Market Price

Extreme power price volatility is a relatively recent happening brought about by a host of event but primarily the deregulation of wholesale power generation. Low prices and excess generation would negatively impact the economics of the proposed LM6000 project. But it is unlikely that this will be the case over the next ten years as the state struggles to add sufficient capacity to keep up with load growth and the replacement of older generators. And the LM6000 project only provides a portion of the supply required to meet participating NCPA member loads. Also, if market prices and power availability were favorable, the LM6000 could be cycled or idled during these periods.

- Dry Hydro Impacts

With the transistion of the Western contract to a supply similar to a hydro project, coupled with the CT2 owners existing participation in NCPA's Collierville Project, the impacts of dry hydrological conditions will have cost impacts on serving native loads. Typically these conditions produce compound effects: 1) less water in the reservoir reduces available energy to meet load, and 2) other hydro drainage areas also experience poor water / reduced energy output conditions and thus drive up market prices. So not only do you need to buy more energy, you must pay a higher price for it.

The following table shows the CT2 owners' projected increased annual energy needs resulting from a change from average to dry hydro conditions.

CT2 Total Energy Need (Year 2005, Dry Hydro Conditions)	
Participant	Year 2005
	aMW
Alameda	9.1
Lodi	19.4
Lompoc	7.0
Roseville	69.2
Total	105.5

The total energy needed by the CT2 participants during 2005 under dry hydrologic conditions is over 105.5 aMW (924 GWh) and this energy will either be produced by a new plant or purchased from short- or long-term market purchases. The LM6000 project has the capability of providing over 40% of this energy deficit and thus a significant market hedge during these conditions.

7) SUMMARY / CONCLUSION

Participating in a new resource endeavor has it share of risks and rewards. The CT2 owners have a need for new wholesale supply over the next ten years and the LM6000 project will meet a share of this need. That Enron may receive an ISO capacity payment contract for this unit resulting in $8 million annual payments for the first three years of operation presents a unique opportunity to defray over half of the total plant purchase price of $43.9 million. This plant also affords the opportunity to increase the utilization of the existing STIG site which was designed to accommodate additional generation such as the LM6000 unit.

It is reasonable to conclude that this plant is an economic alternative to meet power supply needs and participating CT2 owners should take necessary steps to purchase this unit from Enron upon commercial operation, given appropriate guarantees on purchase price, ISO capacity payments, and the expected market value of plant output.

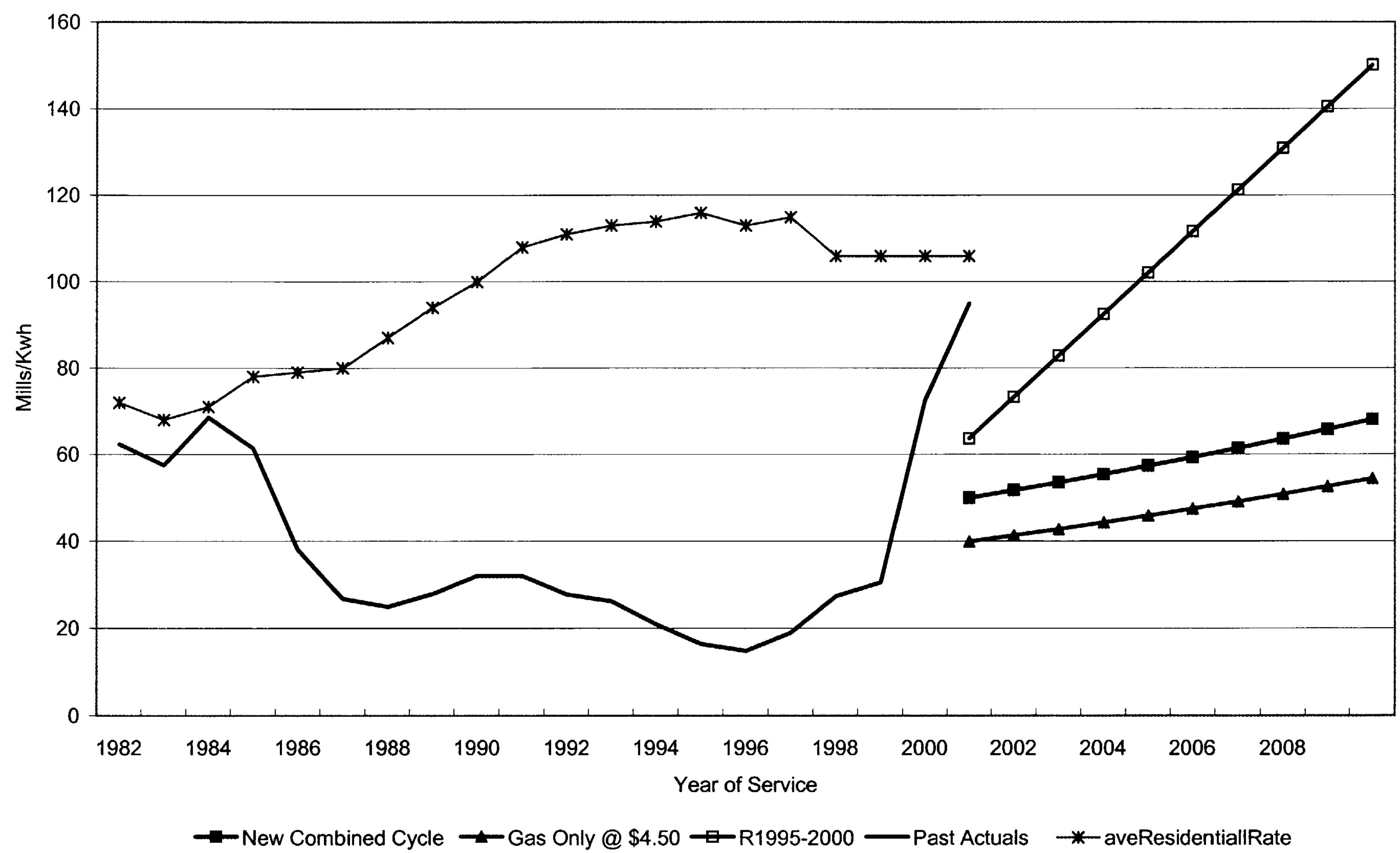
filed 11-15-00

City of Lodi

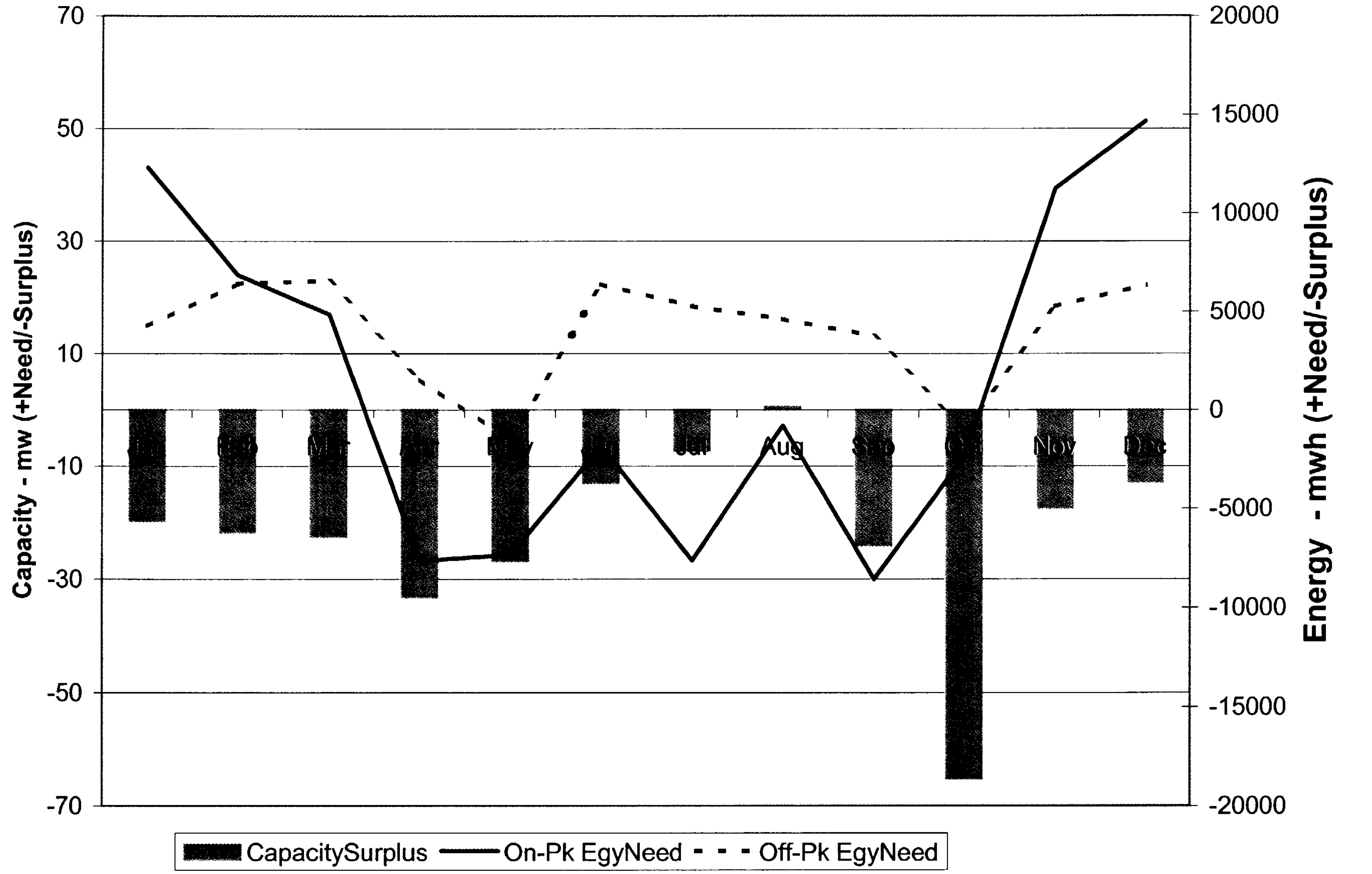
		2001 Capacity -- mw	
		summer	winter
CoPk		135.6	65.7
Geysers	geothermal	14.9	14.9
Combustion Turbine #1	gas	42.6	42.6
STIG	gas	23.8	9.0
Calaveras	hydro	24.8	24.8
Seattle City Light	exchange	23.3	-20.0
Western	contract	2.0	2.0

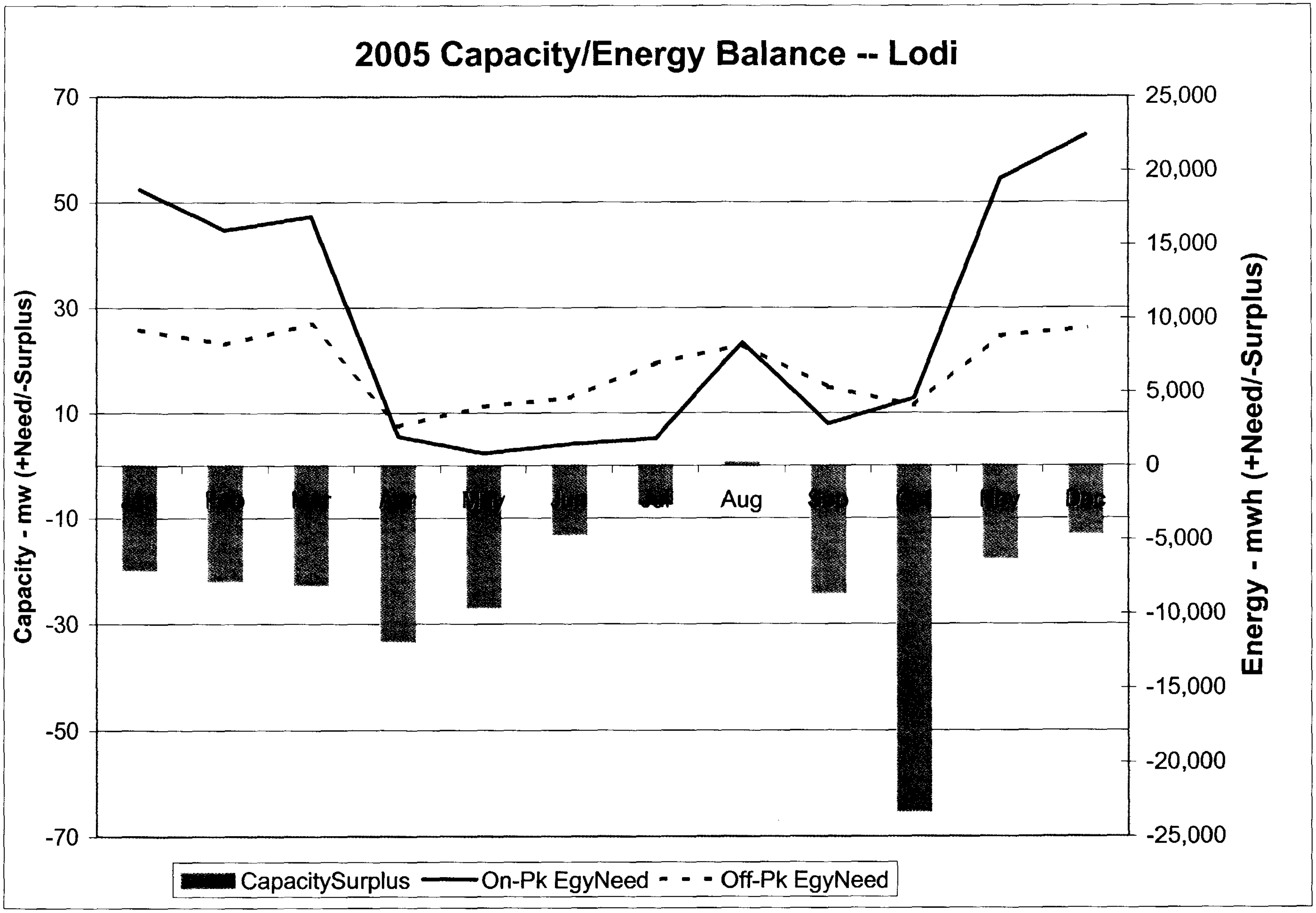
Ownership of existing LM5000 and site		genericLM6000
Alameda	19.0%	8.6 mw
Lodi	39.5%	17.8 mw
Lompoc	5.0%	2.3 mw
Roseville	36.5%	16.4 mw
total	100.0%	45.0

California Power Prices
Past and Future, 1982 - 2010



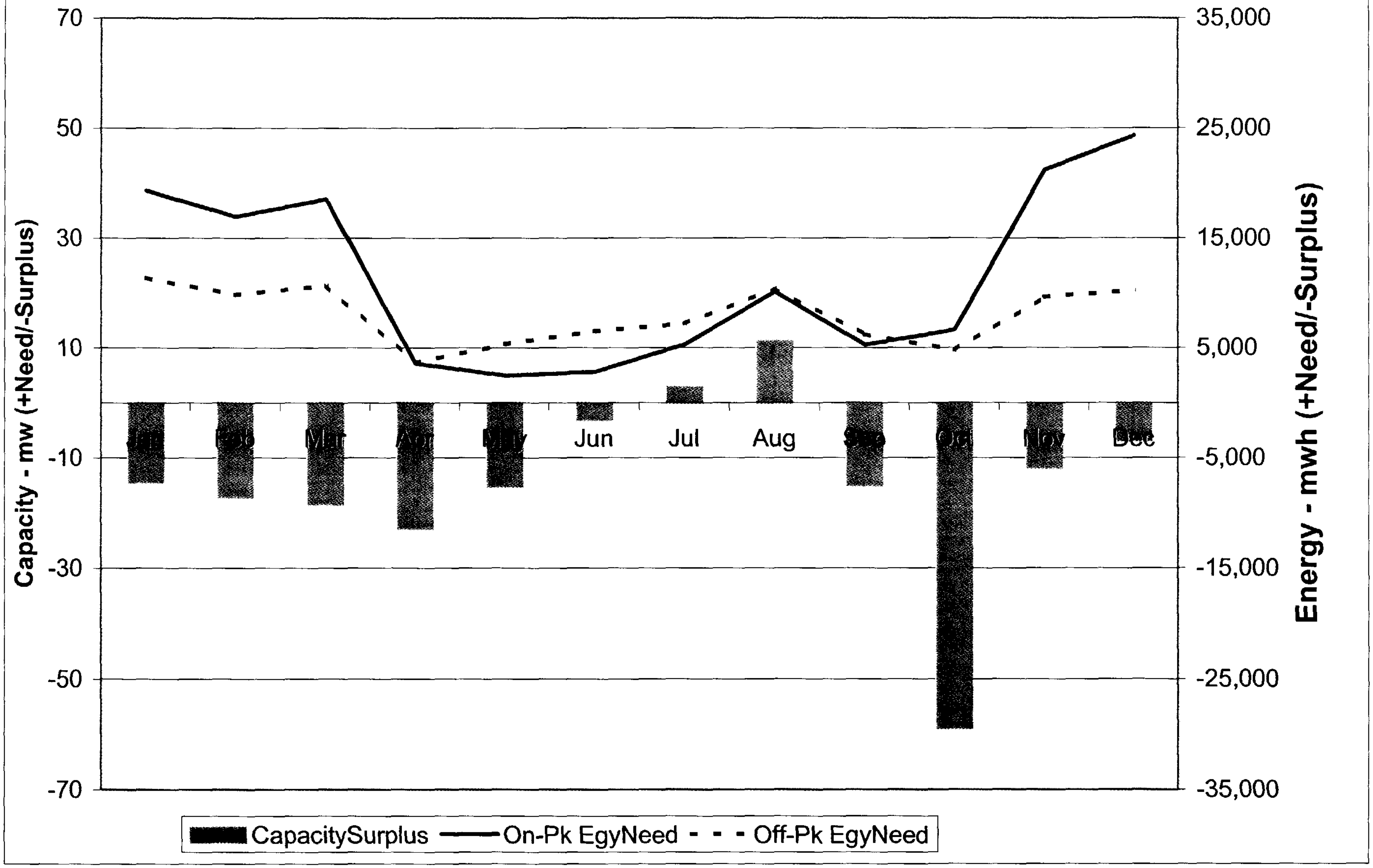
2001 Capacity/Energy Balance -- Lodi





2005 Capacity/Energy Balance -- Lodi
Capacity - mw (+Need/-Surplus)
70
50
30
10
-10
-30
-50
-70
Energy - mwh (+Need/-Surplus)
25,000
20,000
15,000
10,000
5,000
0
-5,000
-10,000
-15,000
-20,000
-25,000
Aug
CapacitySurplus
On-Pk EgyNeed
Off-Pk EgyNeed

2010 Capacity/Energy Balance -- Lodi



Recommendations

- Perform Pilot Testing of Winter Percolation Discharge
- Submit Application to Regional Water Quality Control Board for New Discharge Permit for Both Discharge to Bishop Cut and Winter Percolation
- Begin Discussions about Purchasing or Otherwise Obtaining Operating Control of Land Needed for Alternative Implementation
- Continue Public Participation Process

Costs for Alternatives

Alternative	Capital Cost ($M)*	O&M Cost ($M)*	Annualized Cost ($M)
DC-D – Discharge to Dredger Cut, Tertiary Treatment, Source Control & Facility Upgrades – No dilution in Dredger Cut, may be unable to meet future discharge requirements	$33.8	$1.19	$4.57
DC-W – Discharge to Dredger Cut via Wetland, Tertiary Treatment, Buy 130 Additional Acres, Additional Storage & Facility Upgrades – No dilution in Dredger Cut	$35.3	$1.22	$4.75
BC-D – Discharge to Bishop Cut via Pipe, Tertiary Treatment, Buy Pipeline Easement, Source Control & Facility Upgrades – Better dilution in Bishop Cut	$33.2	$1.17	$4.49
BC-W – Discharge to Bishop Cut via Wetland, Tertiary Treatment, Buy 100 Acres @ Bishop Cut, & Facility Upgrades – Better dilution in Bishop Cut	$33.7	$1.20	$4.57
BC-PD – Partial Discharge to Bishop Cut via Pipe & Land, Denitrify, Buy 260 Acres East of Thornton Rd. & Pipeline Easement, Source Control & Facility Upgrades (Secondary)	$31.3	$0.95	$4.08
BC-PW – Partial Discharge to Bishop Cut via Wetland & Land, Denitrify, Buy 260 Acres East of Thornton Rd. & 60 Acres at Bishop Cut & Facility Upgrades (Secondary)	$30.8	$0.92	$4.00
LD – Total Land Discharge, Denitrify, Buy 400 Acres East of Thornton Rd. & Facility Upgrades (Secondary Treatment)	$33.9	$0.86	$4.25

* Facility Capital Cost of $16.5 Million and O&M Cost of $0.58 Million common to all alternatives and is included above.